Alberta's New Oil Sands Royalty System

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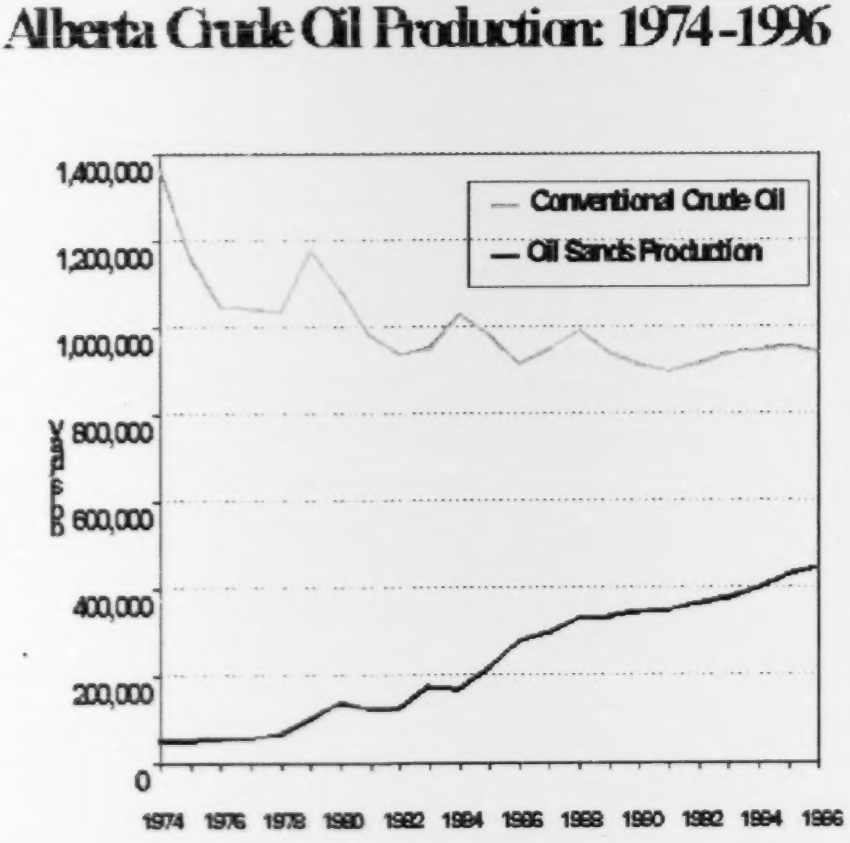
Note: This paper was presented May 2, 1996, therefore key issues and options are included rather than the definitive positions that will be used for the new regulation. Furthermore, any positions, ideas or options regarding the new oil sands royalty system included in this paper is subject to change.

Introduction

On November 30, 1995, Premier Klein announced a new royalty system for Alberta's oil sands. The new system is a modified form of a resource rent royalty. The announcement of this new royalty system was the product of several years of collaboration between industry and government. Alberta's oil sands offer both challenges and opportunities. Oil sands developers are overcoming many of the challenges and are realizing the immense potential of this world scale oil resource. Through actions like the new oil sands royalty system, Alberta is demonstrating its commitment to the development of the oil sands.

I. Background

The Potential of the Alberta Oil Sands
As the supply of conventional oil in North America declines, consumers will turn to non-conventional and frontier sources of petroleum to avoid a growing dependence on resources from outside of the continent. Fortunately, Alberta has huge deposits of oil sands that underlie about 77,000 square kilometres (30,000 sq. miles) of the province. The oil sands contain about 1.7 trillion barrels of oil in place, of which approximately 300 billion barrels are ultimately recoverable. Alberta's oil sands are poised to play a growing role in meeting the demand for oil in North America.

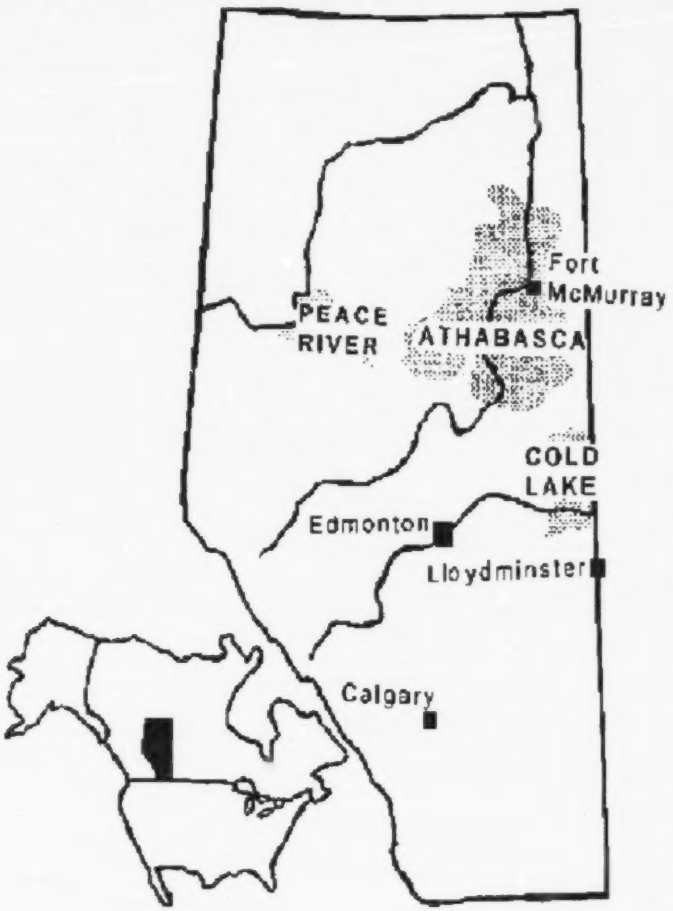


The existence of this vast amount of oil has been known for many years, but the technical knowledge to economically exploit this resource did not exist. The Government of Alberta has played a major role in encouraging and promoting the development of the oil sands through technology and research programs. Achieving sustainable and efficient development of the oil sands has been Alberta's objective for many years. Alberta's strategy for oil sands development is aimed at unlocking the potential of the oil sands that for the long-term prosperity of the province.

Attributes of the Oil Sands

The crude that is extracted from of the oil sands is called bitumen. Bitumen is defined in Alberta as a highly-viscous, naturally occurring hydrocarbon. In its natural state bitumen is not recoverable at a commercial rate using conventional means. The bitumen extracted from Alberta's oil sands is generally less than 12 degrees API, but this can vary by deposit. Generally, any crude that is below 15 degrees API is considered to be bitumen. This compares to light crude which is generally defined as crude oil that is greater than 30 degrees API, and heavy oil is usually classified between 15 to 30 degrees API.

Saturation levels of bitumen in the sand also vary from less than 1% to 18%. Oil sands reservoir are located from surface levels, to deposits at depths of more than 760 meters. Alberta's oil sands reserves are located in three main geographic areas: Athabasca, Cold Lake and Peace River. As a result of the varying bitumen saturation levels, location, and geological diversity of the oil sands, the technology and approach required to extract this resource is distinct for each area, and even for zones and reservoirs in the same area.



Exploitation of the Oil Sands

The two most common methods of extracting bitumen from the oil sands are surface mining and *in situ* ("in place") extraction. The reserves that are economically mineable from the surface lie under less than 75 meters of overburden.Overburden is a layer of sand, gravel, and shale between the surface and the underlying oil sand. This layer must be removed before oil sands can be mined by surface extraction methods. Most of the remaining reserves lie below 200 meters, and the recovery of bitumen at this depth is typically economical only by using *in situ* extraction technologies. *In situ* recovery refers to methods to extract the bitumen from the deposit without removing the overburden or the sand itself. Technology advances in both surface mining and *in situ* recovery have occurred over the past several years, reducing unit costs and improving recovery rates.

Bitumen is normally too viscous to be transported by pipeline in its natural state. To decrease its viscosity before shipment, a diluent such as natural gas condensate can be added, or the extracted bitumen can be upgraded into synthetic crude oil on the project site. As Alberta is a major gas producing region, available condensate supply has enabled many of the *in situ* operations to ship bitumen to market in a diluted form. This abundance of condensate and the market ability to ship this diluent to the various projects may be constrained in the future as more and more *in situ* projects begin production.

II. Alberta's Oil Sands Industry

Oil Sands Production - Surface Mining

About 1,800 kilograms (nearly 2 tonnes) of oil sands must be mined to produce one barrel of light, sweet synthetic crude oil. Alberta currently has two commercial surface mining, extraction and upgrading projects: Syncrude Canada Ltd. and Suncor Inc. Oil Sands Group. Facilities that have the capability to extract and upgrade bitumen into synthetic crude oil are known as integrated projects. Upgrading converts the heavy bitumen into a light synthetic crude oil by increasing the hydrogen-to-carbon ratio. This can be done by either removing carbon (coking), or by adding hydrogen to break down the larger, heavier and more complex hydrocarbon molecules into simpler lighter molecules. The primary products produced from upgrading are naphtha, used for the manufacture of gasoline, middle distillates such as diesel, kerosene and jet fuel, and gas oils. By-products include sulphur, butane, fuel gas and coke or pitch.

In 1996, Suncor Inc. produced a total of 28.5 million barrels of synthetic and custom blended crude oil (78,000 barrels per day). Syncrude Canada Ltd., produced approximately 73.5 million barrels of synthetic crude oil in 1996 (over 201,000 barrels per day). The more than 100 million barrels of synthetic crude oil produced by the two oil sands mining operations in 1996 represented about one fifth of Alberta s total crude oil production, and over 15 per cent of Canada's total crude oil production.

Oil Sands Production - *In Situ*

The reserves of bitumen suitable for *in situ* recovery methods are almost 10 times the size of those accessible by surface mining. Where feasible, recovery of bitumen from *in situ* operations makes use of thermal techniques in which the oil sands are heated while still in the ground. One of these techniques is the process of cyclic steam stimulation. In this process high pressure steam is injected into the oil sands formation, heating the bitumen. Following steam injection, the formation is allowed to soak for a period of time. After the formation has been sufficiently saturated with steam, the injector well is converted to a production well, extracting steam, water and bitumen. Once production drops below economic rates, the process is applied to the reservoir again.

The largest of the commercial *in situ* projects in Alberta is Imperial Oil's Cold Lake facility. Construction of this project, which uses cyclic steam stimulation began in 1983. The Cold Lake project is being developed in pairs of phases, with each phase capable of producing approximately 10,000 barrels of bitumen a day. By the end of 1985, four phases plus two pilot plants were producing about 50,000 barrels/day. Since then, additional phases have been added boosting production to over 90,000 barrels/day.

Recent advances in *in situ* production technology, such as steam assisted gravity drainage (SAGD), allow for thermal *in situ* projects on a much smaller scale and potentially improved production economics. SAGD technology appears to be suitable for widespread commercial applications in the Alberta oil sands. As well as SAGD, a new generation of horizontal drilling systems, are enabling production from some reservoirs where the net pay zone is too thin to commercially apply thermal recovery technologies.

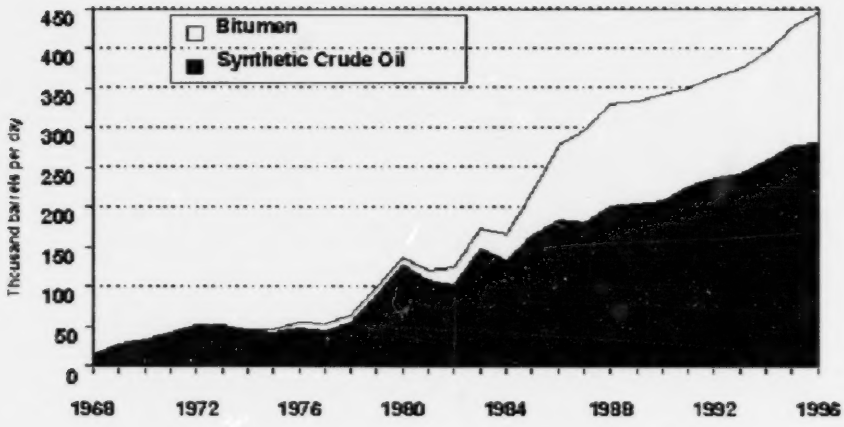
A typical grassroots thermal *in situ* project today might cost approximately $200 million in initial capital ($96). It would take up to 3 years of construction before startup, and produce at a rate of about 35,000 barrels per day.A typical grassroots project economics has been estimated by the National Task Force on Oil Sands Strategies. With ongoing sustaining capital investments, thermal *in situ* projects have the ability to maintain these production levels for decades. The lifespan of any oil sands project is, of course, a function of its reserve base, and the employed production rate. At current levels of costs and market prices, the planned lifespan of oil sands projects might be 30 years or more, with production being maintained or increased throughout the life of the project.

Aggregate Oil Sands Production

Production from Alberta's oil sands commenced in 1967 with the startup of the Suncor plant (then known as Great Canadian Oil Sands). Syncrude, the world's largest producer of crude oil from the oil sands began production in 1978. In the mid-1980's, the startup of a number *in situ* projects resulted in a significant increase in bitumen production. The majority of this incremental oil sands production was from Imperial Oil's Cold Lake Project. Over the period between 1980 and 1988 production grew at an annual rate of 11.5%.

Between 1988 and 1994, oil sands production maintained a slow, but steady increase of 2.7% per year as existing projects expanded and some new developments occurred. These new *in situ* projects that came on stream included BP Canada/Petro-Canada Wolf Lake, Amoco Elk Point, Dome Lindbergh, Murphy Lindbergh, and Shell Peace River. Many companies were interested in oil sands development during this period, but factors such as low oil prices and relatively high costs resulted in only modest production increases.

Over the past few years, oil sands interest has been renewed because of factors such as technical advancement, reduced operating costs, and improved recovery factors and strong market demand. Total production from the oil sands by 1996 reached approximately 445,000 bbls/day, made up of 279,000 bbls/day of synthetic crude oil (SCO), and 166,000 bbls/day of bitumen. In 1996, Alberta's oil sands provided close to 25% of Canada's liquid petroleum production.



Oil Sands Production: 1967-1996

Royalty Terms of Existing Projects

Prior to the announcement of Alberta's new generic oil sands royalty system, each project's royalty terms were negotiated on a project by project basis. This was manageable due to the limited number of projects that were commercially active in Alberta.

Suncor

Before 1987, all of Suncor's royalties were based on a gross production. In 1987, Suncor moved to a net revenue royalty system with a minimum royalty. Royalties are calculated as the greater of 30% of net revenues or 5% of gross production. Allowed capital and operating costs are grossed up by 1% and 10% respectively, for determining net revenues. In any year when the minimum gross royalty exceeds the net royalties calculated, the difference is carried forward to future years as a deduction against royalties payable when the net royalty becomes greater than the gross royalty.

Syncrude

Syncrude pays 50% of the project's deemed net profit to Alberta as royalty. It does not have a minimum royalty on gross production. Therefore, in any year when the net royalty calculated is negative, no royalties are paid.

Cold Lake Regime

Typically, the royalty terms applicable to commercial *in situ* projects prior to the announcement of the new generic royalty system were based upon the royalty terms provided to Imperial Oil's Cold Lake project. This royalty consists of a 1% royalty on gross revenue at startup, increasing by 1% every 18 months to a maximum of 5%. The royalty then remains at 5% of gross production until payout (when gross revenue exceeds cumulative operating costs, capital costs, gross royalty, and a 10% return allowance on unrecovered costs), at which point it converts to the greater of 30% of net revenues or 5% of gross production. Capital and operating costs are grossed up by 1% and 10% respectively, in the calculation.

Unique Royalty Arrangements

Negotiations on a project by project basis allowed for flexibility in royalty arrangements to accommodate project specific concerns. An example of the unique arrangements put in place was recent modification to Suncor's royalty terms. The arrangement allowed Suncor to a reduce its royalties payable from January 1, 1992 to December 31, 1997, in conjunction with approved capital programs to abate odour and SO2 emissions. See P. Precht, R. Germain and D. McMurray, for a more detail on the royalty terms of specific projects.
Years of project specific arrangements in the oil sands resulted in an overall inharmonious royalty system. Oil sands developers agreed that Alberta's ad hoc oil sands royalty system led to uncertainty about the royalty terms that would apply to their future investments. Investors contemplating oil sands development didn't have a transparent royalty structure on which to evaluate investment plans and existing oil sands companies were not sure about the future royalty structure new investments or expansions might face. There was a need to construct a formal royalty structure for the oil sands industry.

The National Oil Sands Task Force

The steering committee for the National Task Force on Oil Sands Strategies was formed by the Alberta Chamber of Resources in 1993. This committee consisted mainly of representatives from the oil sands industry and supporting industries, as well as representatives from both the provincial and federal governments.
The Task Force's mission was:

To be a catalyst for the further development of Canada's oil sands resource through identification of a clear vision for growth and preparation of a plan of action. This will be achieved through a series of assessments regarding technological, socio-economic, environmental and marketing aspects of oil sands development. The Task Force will identify new concepts, technologies, and strategic approaches and communicate the results to key private and public sector decision makers.

One of the barriers to development which the Task Force identified was the ad hoc structure of royalty agreements. The Task Force recommended that a generic royalty system be adopted to create fiscal certainty and stability in the encouragement of oil sand investment. This uniform royalty structure would also place all new projects on a level playing field.

In the spring of 1995, the Tasks Force released a comprehensive report outlining a detailed list of recommendations for the oil sands industry. The Task Force proposed a uniform oil sands royalty system based on a specified percentage of net project revenues after all costs are recovered. This type of resource rent royalty had been used in the ad hoc oil sands agreements for decades. By the end of 1987, all existing oil sands projects that held royalty agreements had some form of a net revenue royalty. Alberta's experience with net revenue royalty agreements provided a foundation for the Task Force's recommendations and for the new royalty system to promote investment in oil sands development.

III. The New Alberta Oil Sands Royalty System

Alberta had a number of objectives which led it to develop the new oil sands royalty system:
Accelerate the development of the oil sands -- ensure that developers are placing a high priority on oil sands development in order to meet the market opportunities available for oil sands products over the short to medium term.

Facilitate development of the oil sands by private sector companies. Alberta no longer directly participates in development through grants, loans or loan guarantees. Development must occur because businesses expect to make a reasonable profit from the venture.

Ensure that oil sands development is competitive with other petroleum development opportunities on a world scale. Alberta's oil sands offer many attractions, including the huge size, well developed infrastructure including pipeline connections to US markets, and a welcoming political climate. Alberta wants to ensure that the royalty system for the oil sands supports these advantages by facilitating the development of the resource.

Resource Rent Royalty Framework

The resource rent royalty approach to rent collection has been widely accepted by many legislators and economists. This form of rent collection allows the investor to achieve a specified threshold rate of return on a project before rent is extracted (Appendix A describes economic rent and its collection). After the investor achieves this threshold return on a cumulative basis (project payout), the resource rent royalty commences on all further positive cash flows. In principle, the threshold rate to determine the date of project payout should reflect the investor's hurdle rate for the project. If this rate can be determined and implemented, then the extraction of the rent will not discourage long-term investment decisions. If the rates that are employed by government are below those of the investor without any other offsetting incentives, future projects may be deterred. The main advantage that this type of resource rent royalty has in the oil sands industry is that capital investment risks are shared with government to a greater extent than in Alberta's conventional royalty system.

Alberta made use of many of the recommendations of the Task Force in developing the resource rent royalty to standardize the oil sands royalty system. The basic elements of the new system are:

Minimum 1% royalty payable on all production.

25% royalty payable on net project revenues after the developer has recovered all project costs including a return allowance.

The return allowance set at the Government of Canada Long-Term Bond Rate (LTBR).

All project cash costs (operating and capital) are 100% deductible in the year incurred.

The new oil sands royalty system follows many of the principles of the resource rent tax.See Ross Garnaut and Anthony Clunies Ross

(p. 97-99) Putting aside the 1% minimum royalty for the moment, the main part of the oil sands royalty is the 25% participation in the net revenues of the project after payout. Through this feature Albertais participating with the developer in the sense of being a project partner whose return is linked to the project's success. Only when a developer's cumulative project cashflows exceed operating and capital costs as well a return on invested capital equal to the LTBR, does Alberta participate in a significant royalty.

This approach to the royalty was chosen due to the high cost and the associated high risk nature of oil sands investment. Production based royalties would have been less sensitive to project profitability than the resource rent royalty. Because the oil sands face higher barriers to development than many other types of petroleum (less valuable product due to the low API, higher technological risk, higher capital costs and higher operating costs etc.) the additional burden of a significant production based royalty was determined not to be appropriate.

The Task Force recommended that the net revenue royalty rate be set at 25%. Based on the analysis the Task Force completed, this rate was viewed as providing an appropriate incentive for oil sands development, while still providing a sufficient return to Alberta from the oil sands resource. In combination with federal and provincial income taxes, after project payout, a 25% net revenue royalty results in the developer receiving marginal project income of a 38%, with the balance of 62% going to the federal and provincial governments through royalties and corporate income taxesAnalysis based upon net present value of corporate and government revenues

discounted @ 10%. Based upon a typical grassroots project economics estimated by the National Task Force on Oil Sands Strategies (1995).. Developers pay other taxes, such as municipal property taxes, as well.

In theory, Alberta could attempt to capture to 100% of the economic rent from an oil sands project. This could mean that when the developer recovered his costs, including a return equal to his risk adjusted cost of capital, Alberta would receive 100% of incremental project revenues. This would have been inappropriate because:

Cost reduction has been a key factor in making oil sands development more attractive. A royalty rate that captured too much marginal cashflow would have resulted in a reduced incentive for cost reduction and innovation. This is the "gold plating" argument that if marginal tax rates are too high there is an incentive to spend additional cashflow rather than seeing it go to governments through royalties and taxes which provide no tangible benefit to the project.The measurement of project costs is a difficult matter, particularly when project related activities are performed at corporate offices located away from the project and when there are inadequate systems to allocate corporate overheads such as management and computing costs.

The federal corporate income tax system is not integrated with Alberta's royalty system -- rather than providing for the deductibility of royalties in the calculation of federal taxable income, the system allows for a "resource allowance" which is 25% of defined "resource profits". This resource allowance could result in double taxation if the royalty rate is set too high.

If the net revenue royalty rate is very high, the return allowance rate would have to equal a developer's risk adjusted cost of capital in order to ensure that royalty is only collected on the project's economic rent rather than on the return to capital. Even if accurate identification and measurement of all project costs could occur, each project would still have a unique risk adjusted cost of capital. The simpler approach chosen is to establish a single return allowance rate for all projects. Alberta chose to set the return allowance rate below developers' cost of capital, and the net revenue royalty rate below the level that would capture 100% of the project's rent.

By not trying to measure all project costs exactly, and leaving the potential for developers to capture some of the economic rent of successful projects, Alberta's royalty system encourages developers to innovate to maximize the efficiency and resource recovery from their projects.

The Return Allowance

The return allowance rate is a key feature of the resource rent royalty system because it is a significant factor in determining when a project moves to the 25% net revenue royalty. The Task Force ran numerous scenarios and concluded that a return allowance in the range of the Government of Canada LTBR to the LTBR +2% would be appropriate. The Task Force's recommendation was that the rate be set at the higher end of the range.

Factors which are important in setting the rate include:

the developers' cost of capitalthe expected returns on investment and project hurdle ratesthe risk profile of the projectsinflation, interest rates and other capital market factors

Developers will only invest in oil sands projects if they expect to earn at least their risk adjusted cost of capital over time. However, due to the risks of oil sands development the time until the developer achieves this objective can be relatively long - potentially 5 to 10 years. If the return allowance rate was set at the developer's risk adjusted cost of capital, the project could appear to be profitable (generating significant positive cashflow) without paying any significant royalty prior to payout. Both the Task Force and Alberta agreed that this would be an unstable system, with the potential for a future government to make changes to capture a greater percentage of the project's cashflow.

In setting the return allowance rate at the Government of Canada LTBR (currently about 7%), the net revenue royalty becomes payable earlier than it would be if the return allowance was higher. On successful projects developers will pay net revenue royalty prior to fully achieving the targeted return from the project. However, Alberta leaves a portion of the economic rent of successful projects for the developer to capture -- the developer therefore pays royalty earlier in the project's life but less later in its life, than if the return allowance and net revenue royalty rates were higher.

The Minimum Royalty

The ad hoc oil sands agreements for existing developments generally included a 5% minimum royalty. This minimum royalty was significantly below the production based royalty payable on conventional oil production.

However, the Task Force viewed the 5% minimum royalty as a barrier to development in that it was a drain on developers' financial resources during the times that they could lease afford it -- during project start-up and times of low prices. The Task Force recommended that there be no minimum royalty.

Alberta agreed in concept with the Task Force that minimum royalties tend to discourage development. However, as owner of the resource,

Alberta was not willing to move completely away from a minimum royalty. The 1% minimum included in the new regime guarantees that the province will receive some royalty from every barrel of oil produced. Its low level should not make it a significant barrier to development. Minimum royalty paid will be an allowed cost (like operating or capital costs) in calculating the timing of the project's payout.

The minimum royalty, and the return allowance set at the LTBR (a level below the developer's risk adjusted cost of capital) are both departures from the resource rent royalty in its pure form. Both will provide Alberta with royalty revenue from projects prior to the developer fully recovering project costs. Both will help taxpayers in Alberta see the benefits of oil sands development via the royalty system as well as through the jobs that development will create. In this way, both will work to ensure that the royalty regime is stable and enduring, and therefore can be counted on by developers in making large, long-term capital investments.

IV. Issues in Implementing the New Oil Sands Royalty System

Industry Consultation Process

At the present time, the Alberta Energy Department is working to implement the new oil sands royalty system. Since January of 1996 the Department has been having informal discussions with oil sands companies about their development plans and reviewing existing oil sands Crown royalty agreements to determine which parts of the agreement could be kept and which aspects need to be changed. Two important issues are set out in this paper:

project definition the definition of project costs and revenues

During April of 1996 formal presentations on options being considered for implementing the new royalty system were made to three oil sands industry associations. A discussion paper setting out issues and potential solutions was distributed, together with an industry survey to facilitate feedback. Industry has continued to play a important role in commenting on various drafts of the regulation between the time that this paper was presented in May, 1996 and mid - 1997. The final regulation is expected to be passed by the end of 1997. As the consultation process for implementing the new royalty system through the development of business rules is an ongoing process at the time of writing this paper, key issues and options are included rather than the definitive positions that will be used for the new regulation.

What is an Oil Sands Project?

The definition of a project can have a significant impact on how a net revenue royalty is implemented, as well as how developers respond to it. For example, a narrow project definition, without a provision for unrecovered costs to be carried from one project to another, may result in Alberta sharing less of the down side risk of oil sands development than it would under a broader definition. However, there is a potential under a very broad definition for a developer to continually invest, pushing back the date of project payout.

To this point, Alberta has defined oil sands projects on a basis similar to the one used by the Alberta Energy and Utilities Board (AEUB). This independent regulatory Board has the legislated responsibility to ensure that Alberta's resources are developed in an orderly fashion for the maximum benefit of Albertans. The AEUB approves projects in the oil sands if the proponent is able to demonstrate the project meets the legislated criteria. In the past, developers tended to assemble large blocks of land prior to seeking AEUB approval to develop a project. These larger projects were subject to public hearings and potentially a separate environmental impact assessment prior to the AEUB approving the planned development. These large developments were relatively easy to identify as discrete projects.

Large projects are still being developed and proposed. However, many smaller oil sands developments are also beginning to appear. These projects are characterized by smaller, non-contiguous land bases, initially incomplete infrastructure and an incremental approach to development. Projects may make use of recent advances in drilling technology (e.g. multi-lateral horizontal wells), pumping technology (e.g., progressive cavity pumps) or steam injection technology (e.g., single well SAGD -- steam assisted gravity drainage). Some project proponents tend to target geographic areas that are amenable to development using their approach, and then

build upon success by adding additional lands and facilities to the project as their experience with the technology and the reservoir conditions increases. Under these development scenarios, identifying the project boundaries for royalty purposes becomes more complex.

Two alternatives to the approach of using the AEUB definition have been presented in the industry consultations now taking place. The first takes an "economic unit" approach. Here the project proponent(s) would propose the project to the Department, which would then approve it under broad qualifying guidelines. One advantage of this approach is, where there is more than one lease owner involved in the project, all lease holders could agree to be bound by a single royalty calculation and the project operator could be made responsible for the payment of the project's royalty. This would be similar to a unitization in conventional oil development. It allows for different ownership arrangements in different aspects of the project, with the project royalty be calculated as a single amount and the owners then determining among themselves the sharing of the obligations for payment. This approach can accommodate developers who are unable to assemble large contiguous tracts of land, but who nevertheless operate their activities within a geographic areas as a single project.

The second alternative that has been proposed by some in the industry, is to have all of a developer's interests in the oil sands (or in each of three sub-areas of the oil sands) combined into a single project. The key factor in defining a project would be ownership, and the approach could be viewed as closer to a type of "oil sands income tax". This approach could remove any incentive for a developer to invest in one activity ahead of another because it was paying the 1% minimum royalty while the other was paying the 25% net revenue royalty. A dollar invested would have the same impact on royalty no matter which area it was invested in.

However, this approach may become complicated where there are multiple owners in a development. For example, if a company is a majority owner in one development should its interest in the development be commingled with its 100% working interest activities? Should it be commingled if it is a minority interest holder in the development? What about if it is a minority interest holder and not the operator? This approach to project definition would be a significant departure from the system now in use in Alberta.

Either of these approaches would be a broader definition of a project than that which was used for royalty agreements in the past. Crown royalty agreements limited the project to the area approved by the AEUB, plus any additions approved by the Minister where substantial work commenced by the 10th anniversary of the agreement. Effectively, the project was limited in terms of geographic area, reserves and time, to increase the certainty of the province receiving the net revenue royalty.

Approaches to project definition which accommodate developers who wish to start small and add additional lands over time, rather than waiting until a large block of land is assembled and a large project is approved may support oil sands development. The challenge is to ensure that projects are defined in a way that prevents royalty avoidance, while still allowing reasonable project additions.

Considering new approaches to project definition is possible in part because the new royalty system will likely be implemented through regulation rather than agreements. Changes in development patterns can be more easily accommodated by changes to a single regulation which affects all developers equally, rather than requiring the renegotiate separate agreements for each project.

Project Revenues and Costs

The definition of a project is important for determining which revenues and costs are included in the calculation of net project revenue. In Alberta's system, project revenues will be based on the value of the product sold in arms length transactions. Costs incurred for transportation of the bitumen from the physical boundary of the project to the point of sale are allowed deductions in arriving at the unit price of the product. Tests will be put in place to ensure that these costs are reasonable where there are non-arms length transactions involved.

Where a developer undertakes activities related to his oil sands project and includes the cost of the activity in the calculation of royalty, any related revenue will also be included in the calculation of royalty. An example might be a developer who builds an oversize cleaning plant on his project and then custom processes the bitumen of another developer. If the costs of the cleaning plant are included in the calculation of project net revenue, the related custom processing fees would also be included. A similar treatment would apply to technologies developed as part of the project that were later sold or licenced, or cogeneration activity that was undertaken in relation to the project.

It is proposed that a project cost must meet the following four tests to be allowed:

It is directly attributable to the oil sands project.It is reasonable in relation to the circumstances in which it is incurred.It is incurred by the lessee after the project's effective date.It is incurred in connection with the production or delivery of the bitumen or other leased substances to the project's boundary, or to provide related field, office administrative or other services.

These tests would determine which costs could be allowed, and a list of exclusions would set out those costs that would specifically not be allowed. The excluded cost list would include:

Overhead and administrative expenses.Interest or financing charges or penalties for late payments.An overriding royalty interest, net profit interest or similar arrangement.Depletion or depreciation.Non-cash costs.

Research and development costs were generally not allowed under the Crown royalty agreements in place for existing oil sands projects. Alberta is considering allowing some research and development costs for several reasons:

research and development can be considered to be critical to the continued competitiveness of the oil sands -- not allowing these costs could be viewed as applying the royalty to a quasi-rent that would discourage investment over the long run.As the net revenue royalty is directly linked to the project's profitability, successful research and development activities which increase revenue or lower costs will result in increased royalties. It may therefore be appropriate to consider these costs where they can be directly linked to a project.Alberta continues to place a high priority on research and development and would be pleased to see the annual level of oil sands research conducted in the province increase from the present $100 million per year.

Conclusion The existence of an attractive royalty regime is unlikely, on its own, to create a high level of investment activity. However, where a resource faces significant barriers to development, an inappropriate royalty system can work to prevent development from happening. Alberta's oil sands have faced significant barriers to development, but these are now being overcome through innovations in technology and cost reduction breakthroughs.

Policy changes such as Alberta's new oil sands royalty system are providing the fiscal climate to support the major investments needed to develop this vast resource. By implementing a generic, resource rent style of royalty, with the cooperation of the oil sands industry, Alberta is building on the advantages that it has to offer investors. Investors, including companies with global opportunities, are already moving to build upon these positive developments. Investment in the oil sands may reach $10 billion over the next five years, and production is expected to increase by a significant amount. These developments will help Alberta continue to meet the needs of the North American energy market well into the future.

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Appendix A

Economic Rent Theory

The ownership of energy and mineral rights by the Alberta government, makes the province constitutionally responsible for the proper management of these resources. The majority of the oil sands mineral rights in Alberta are owned by the Province. Development of the oil sands resource is done by private industry by arrangement

with the Province through leasing of the mineral rights. Leasing of these mineral rights maintains the well-defined property characteristics required by private sector to maximize the concept of "rent".

The classical concept of economic rent originated from David Ricardo's theory of land rent.Danielsen Ricardo hypothesized that when superior land was abundant, no rent could be commanded from that land so long as comparable land was available for free. As the best land is used up or taken, it becomes profitable to utilise the next best quality of land, then the next best quality, and so on and so on.Ibid The original Ricardian concept of land rent is then defined as the difference between the cost of producing output on the poorest tract of land that is being used (no rent land) and the value of output on any other tract of land. This concept of rent can be applied to all depletable resources, including oil and gas extraction.

North American oil producers, for the most part, are considered price takers. Some pools will have a lower unit costs to develop than the prevailing price. This amount by which the price exceeds the unit cost is considered the differential or "Ricardian" rent per unit of resource extracted. The general concept of rent can be more clearly defined as the "pure profit" that exceeds the minimum return to induce the investment in that enterprise.

Extraction of Rent

When there is an excess of return above the total economic cost, positive economic rent is being earned. This notion of rent is a fairly straightforward concept, however determining the amount of economic rent for taxation and royalty purposes is a different matter. Economic rents can be highly differentiated due to projects exhibiting different cost structures. One goal of rent extraction, whether it is done by government or by some other party, is to structure the royalty or tax to be investment neutral. Investment neutrality refers to a rent extraction policy that does not affect the investment decisions within that resource industry.

The extraction of "true economic rent" without affecting the flow of investment is possible in theory. True economic rent is the surplus remaining after the returns required to meet the short-term marginal costs of ongoing production as well as the long-term costs of obtaining the resource. Costs such as exploration effect a developer's long-term returns, but may not be directly link to actual production. Removal of these quasi-rents will not have an effect on investment decisions in the short-term, but in the long-term investments for exploration or project development would be hindered. Ross Garnaut and Anthony Clunies Rose

Uncertainty, Risk, and the Supply Price of Investment

In order to extract resource rent and remain neutral in terms of investment decisions, total economic costs must be clearly defined and the supply price of investment must be known. The supply price of investment is the required return potential investors expect on their investment. Without the prospect of such a return, the potential investor will apply his funds elsewhere.Ibid. This expected rate of return depends on the risk associated with a certain project. The expected required return increases as the riskiness of the project increases, assuming investors are risk adverse. Typically, the higher the initial investment or up front capital expenditure, and the longer the payback period in recovering these costs, the greater the risk associated with the project. This profile is demonstrated by most oil sand projects. These projects are also dependant on unstable market prices, such as the variability of oil prices and in the differential between light oil prices and bitumen prices.